Response to the call for input on Ofgem's Locational Pricing Assessment

Thank you for the opportunity to respond to this call for input. The Mutual Energy group includes certified electricity and gas Transmission System Operators whose assets include the Moyle Interconnector between the NI and GB electricity transmission systems, the Scotland to Northern Ireland gas pipeline and much of the NI natural gas transmission system.

We have structured our response along the three high-level questions asked in the call for input.

1. The key opportunities associated with introducing more granular locational pricing in GB

From a theoretical point of view a nodal market is most likely one of the most efficient solutions in the context of network operations and constraints management in an isolated system so it is easy to see the appeal of such a model to NGESO and policy makers. It would provide strong short term locational price signals for investment, whether that be for generation, industry/demand or storage and lead to tangible and obvious reduction in balancing and constraint costs. Prices are likely to be much more volatile than with either zonal pricing or a single national price, so this type of market design seems to present significant opportunity to developers of storage assets. Whilst NGESO has a clear preference for nodal pricing, it is not clear that these opportunities and reduced constraint costs would result in lower whole system costs or outweigh the significant implementation challenges and additional risks to market participants, or indeed if transitioning to location pricing is the best approach to dealing with constraints.

2. The key implementation challenges, risks and mitigations

The main overriding concern with locational pricing is the amount of pricing uncertainty and volatility it would bring. Particularly with nodal pricing, price formation is likely to be so unpredictable and complex that there can be little certainty about its implications for individual projects or market parties. With prices being formed for individual nodes, they will be very sensitive to the impact of any developments near that node (or zone). Forecasts will inevitably need to take account of an increased range of scenarios so investment business cases will carry an increased level of risk – this will lead to increased costs of capital or even stymie investment at a time when massive investment in clean technologies is needed. Whilst a national price does not reflect transmission constraints, its portfolio effect supports investment as it means that prices are relatively stable and not subject to the material short term swings caused by individual projects which we would expect to see under nodal pricing. Even where investment is taken forward, nodal pricing may have an effect of reducing competition within the market, as the complexity and risk may act as a blocker to new entrants whilst giving larger diversified incumbents a natural advantage. Reduced competition is likely to lead to higher costs for consumers.

Another significant issue is that the GB market does not function in isolation and cross-border trading under locational pricing needs to be considered in detail. Whilst driving interconnector flows in the optimal direction to minimise transmission constraints appears to be a key driver of the project, the analysis presented on this matter so far has been quite superficial. It is difficult to see how nodal pricing and central dispatch is compatible with market coupling with neighbouring markets - it increases divergence between the GB and EU market models, thereby further complicating the re-coupling of the GB and EU markets (e.g. through Multi-Regional Loose Volume Coupling). Market coupling is the most efficient way to schedule interconnectors so it is not clear how interconnectors would be efficiently used without market coupling and with a huge number of volatile locational prices within GB – Ofgem will be aware that scheduling interconnectors efficiently without market coupling is already challenging with the relatively simple market of today.

Another challenge is that there are obviously already existing assets and demand centres on the system that will be impacted but will not or cannot move in response to locational pricing. This includes existing interconnectors under the cap and floor regime, capacity market units plus wind farms holding contracts for difference whose commercial business case may be undermined (or improved). The impact of locational pricing on a whole system basis (including the stakeholders of today) should be a key feature of the assessment.

We observe that the proposed nodal approach is very similar in design to a market structure that was previously considered in Ireland between 2003 and 2005[1]. Despite substantial work across industry, at significant cost, this proposed market design was never implemented as drawbacks and implementation challenges became clear at the detailed design and implementation stage. The idea was eventually replaced by the Single Electricity Market (SEM) on the island of Ireland[2], which opted for a single market price rather than locational pricing. This SEM market design has coincided with an almost 800% increase in installed wind generation in Ireland since 2005[3], and renewable generation represented 42% of all-island demand in 2020. It is clear that having a single market price has not acted as a blocker to decarbonising the power sector in Ireland. If locational pricing is deemed necessary on a whole system basis, splitting the GB market into a relatively small number of bidding zones to reflect the main constraints seems like a more feasible and stable option to achieve closer to optimal power dispatch at the day-ahead stage. This type of solution, as seen in other parts of Europe, does not require a fundamental market overhaul and is much more compatible with the current market design.

3. The proposed approach to modelling zonal and nodal market designs

If nodal or locational pricing is 'successful' in its stated aim of resolving transmission constraints, then presumably the constraint zones will be dynamic as the market evolves over the next two decades. It seems that nodal pricing will be very sensitive to any nearby developments (and given that the point is to drive demand to where prices are low and vice versa, stability is unlikely) so account should be taken of the circular relationship between nodal/zone disaggregation, pricing and investment at nodes/zones. Likewise, if nodal pricing is successful in shifting demand and generation from one location to another, then presumably there may be a need for new transmission substations in particular locations and the ability of assets to earn sufficient income to sustain themselves will evolve. Again, this should be considered in the modelling.

How Ofgem would approach transmission network investment decisions going forward should be considered as part of this process and the outcomes of that should factor into assumptions for the modelling. Network investment in other markets that have adopted nodal pricing (for example Texas) is primarily driven by regulatory intervention, rather than congestion income – in other words, transmission constraints generating the highest congestion income (and therefore obvious candidates for resolution) are not necessarily prioritised for investment, rather it is part of a

[1] https://www.cru.ie/wp-content/uploads/2003/07/cer03101.pdf
[2] https://www.cru.ie/wp-content/uploads/2005/07/cer05044.pdf
[3] https://www.eirgridgroup.com/site-files/library/EirGrid/Wind-Installed-Capacities.png

regulatory price control process. As mentioned above, it seems there will be a circular relationship between pricing and investment (including in transmission) – if this can be accounted for correctly then the modelling timeframe should not be impacted by availability of data (such as forecast transmission capacity) as investments under nodal/zonal pricing will be very different than what is expected today.

We understand that total capacity requirement is based on long-term demand forecasts under the National Grid ESO Future Energy Scenarios 2021. As these forecasts are presumably based on national pricing, then if locational pricing achieves its aim, curtailment of renewables (for example) will be significantly reduced. As such, if it is considered that locational pricing will have a significant impact on where generation locates, then generation capacity should be considered endogenously within the modelling.

Additionally, we welcome the acknowledgement that some types of generation (for example nuclear) are fixed to certain geographical locations. In reality, most if not all generator types will face some restrictions on where they can locate. For example, an OCGT will need a strong connection to the gas network – likely at transmission level to access higher pressures – and also adequate access to water for cooling purposes. Varying the strength of such constraints should be considered in sensitivity analysis, for example, by fixing locations for new build OCGTs based on gas network connections and water availability, versus allowing their location to be endogenously determined by the model.

The workshop slides say that there will be no change in risk as a result of nodal price volatility due to management via FTRs. This seems to be a simplistic and optimistic assumption. FTRs are established tools for offering capacity on cross-border interconnectors, and they can be an imperfect tool for managing risk. As FTRs are generally allocated via competitive auctions (and our assumption is that this is how they would be allocated in a locational market – if there are physical constraints resulting in different locational prices then we can anticipate congested FTR auctions) there is a financial risk and cost to buyers of FTRs. There will always be a difference between the price that the FTR auction clears at and what it ultimately pays out and, critically, there is a requirement for available counterparties to trade with to lock in a hedge. Due to the disaggregation of the market, there is likely to be a shortage of liquidity at individual nodes and creation of effective hedges will be more complex.

This issue will be particularly prevalent as the electricity system develops and intermittent renewable generation becomes more dominant. In this case, thermal generators are likely to be running less often than they currently do, acting mainly as 'flexible' generation or peaking plant. As such, they will have to recoup their revenue over a much smaller number of periods and as a result there will be a small number of high-priced periods and a large number of low or zero priced periods. For intermittent renewables, their output is inherently unknown so the ability and value of locking into an FTR-based hedge should be assessed. Again, investors will ultimately factor this inherent risk and uncertainty into their assumptions, and this will lead to higher capital costs or underinvestment.

Interconnectors and storage units will face a lot of similar considerations under potential locational pricing and are both valuable sources of flexibility; however, interaction with connecting markets is obviously a key issue for interconnectors that storage units do not face. As such, in our view grouping the two types of units together as a single stakeholder group is not appropriate so interconnectors and storage should be considered separately.

Final remarks

We note that Ofgem has taken a focused approach to inviting particular stakeholders to its workshops on this topic. Whilst we can understand the rationale for this, such a major potential market change should be developed and considered in a way that is transparent to all significant stakeholders – we believe more representation from the interconnector community at these workshops would be appropriate. It would also be helpful if outputs of the assessment (such as the modelling results) could be shared with industry at an early stage.

Nodal pricing decentralises the imperative to remove or manage constraints away from system operators and on to market participants, which may prove to be inefficient. As part of this assessment it is crucial to also consider what the alternatives are to the introduction of more granular pricing, such as accelerated network build which could address the most material challenges posed by the existing market design.